Chapter Six: Specific Issues Related to Oil and Gas Exploration, Development, Production and Transportation

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A. Geophysical Hazards

Primary geophysical hazards in the Susitna region includes earthquakes, volcanoes, flooding, ice, and current and sediment hazards. The area considered in this finding is located in one of the most seismically active regions in the world, and is in close proximity to several active volcanoes. "In spite of these environmental constraints, petroleum extraction and processing facilities have functioned, both onshore and offshore, without significant environmental damage since the Swanson River field was discovered in 1957." (Combellick et al., 1995:1, citing to Magoon and others, 1976).

1. Earthquake Faulting

Subduction of the Pacific crustal plate (see geology discussion in Chapter Two) accumulates crustal stresses that are periodically relieved by deep-focused earthquakes (See Figure 6.1). Other sources of potentially damaging, shallow-focused earthquakes include the active Castle Mountain fault. In 1984, a magnitude 5.7 earthquake with an epicenter in the Matanuska Valley, near the town of Sutton was attributed to subsurface movement along the Castle Mountain fault (Combellick et al., 1995, citing to Lahr and others, 1986).

The epicenter of the 1964 earthquake (moment magnitude 9.2) was in Prince William Sound. However, geologic effects were widespread and included seismic shaking, ground breakage, landslides and other surface displacements, and falling objects (Combellick et al., 1995, citing to Waller, 1966; Stanley, 1968; Foster and Karlstrom, 1967; Tysdal, 1976). Future strong earthquakes can be expected to produce similar effects. Studies indicate that very powerful 1964-style earthquakes have occurred with an average recurrence interval of 600-800 years during approximately the past 5,000 years (Combellick, 1995). Smaller great earthquakes in the magnitude 8 range probably have occurred more frequently. The most recent pre-1964 great subduction earthquake in the region was 700-900 years ago (Combellick et al., 1995:3, citing to Combellick, 1993).

Other types of ground failure include liquefaction and sliding of water saturated soils; rockfalls; translatory block sliding, such as occurred at Anchorage in 1964; horizontal movement of vibration-mobilized soil, which was the cause of extensive damage to Alaskan railways and highways in 1964, and ground fissuring and associated sand extrusions typical of areas where the ground surface is frozen. Extensive occurrence of all these phenomena has been documented for large earthquakes.

The USGS has recently prepared a series of probabilistic seismic hazard contour maps for Alaska, which are available on the USGS Website at http://geohazards.cr.usgs.gov. These maps depict earthquake hazard by showing, by contour values, the earthquake ground motions that have a common given probability of being exceeded in 50 years. The ground motions being considered at a given location are those from all future possible earthquake magnitudes at all possible distances from that location. The ground motion coming from a particular magnitude and distance is assigned an annual probability equal to the annual probability of occurrence of the causative magnitude and distance. The method assumes a reasonable future catalog of earthquakes, based upon historical earthquake locations and geological information on the recurrence rate of fault ruptures. To prepare these maps, the USGS analyzed all known seismic sources (surface faults,

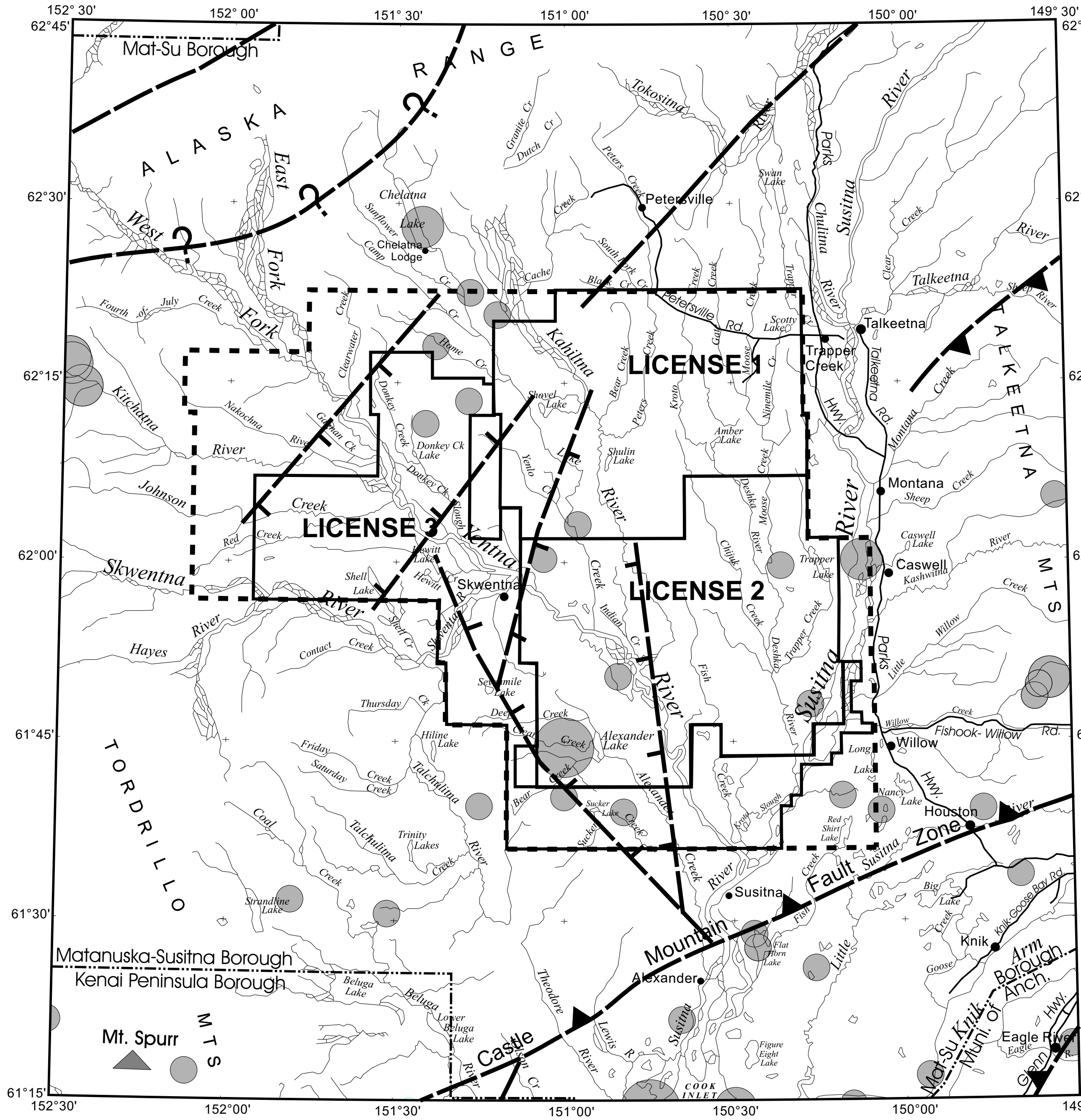
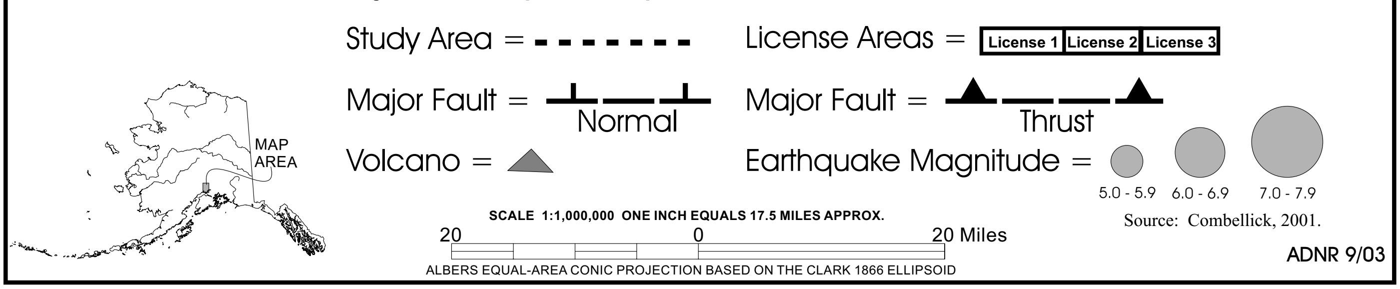


FIGURE 6.1 Major Earthquake Epicenters, Faults And Volcano Locations



subduction zone and volcanic sources). Included in the computations are all historical and instrumental recordings of ground motions, gathered using a grid of 1-sq. km polygons.

The USGS has plans to put the Alaska ground motion hazard data on a CD with a latitude-longitude look-up feature. By entering a latitude-longitude coordinate pair, one will be able to see the probabilistic ground motion for any locale.

This ground motion hazard information is essential to creating and updating the seismic design provisions of building codes. Such information is used by insurance companies to set insurance rates for properties; engineers to estimate the stability and landslide potential of hillsides, and to design earthquake-resistant structures of different heights; and the EPA to set construction standards that help ensure the safety of waste-disposal facilities. At the time a site-specific project is proposed one will be able to call up the probabilistic ground motion values for that specific location.

All structures should be designed and built to meet or exceed the Uniform Building Code specifications for seismic zone 4 (highest earthquake hazard). These potential effects include ground motion amplification, soil liquefaction, and other earthquake induced ground failures. Design, construction, and operation of facilities must mitigate these effects with the goal of preventing loss of human life and significant environmental damage during earthquakes (Combellick et al., 1995:4). It is standard industry practice that facility siting, design, and construction be preceded by site-specific, high-resolution, shallow seismic surveys which reveal the location of potentially hazardous geologic faults. These surveys are required by the state prior to locating a drilling rig.

2. Volcanic Hazards

Alaska contains about 80 percent of all the active volcanoes in the United States and about 8 percent of the active volcanoes in the world. The western shore of Cook Inlet contains six volcanoes that have erupted in Holocene time (10,000 years ago). These are, from north to south, Mt. Spurr, Mt. Redoubt, Mt. Iliamna, Mt. Saint Augustine, and Mt. Douglas. Three of these (Mt. Spurr, Mt. Redoubt, and Mt. Saint Augustine) have erupted more than once this century and could well erupt again in the next few years or decades (Combellick et al., 1995:4).

Study of tephras (volcanic ash layers) in the Cook Inlet region indicates that eruptions have occurred every 1 to 200 years (Combellick et al., 1995, citing to Riehle, 1985). In the 20th century, these events have occurred every 10 to 35 years, and, for the last 500 years, tephras were deposited at least every 50 to 100 years, with Mt. Redoubt, Mt. Spurr, and Mt. Saint Augustine being the most active (Combellick et al., 1995:4, citing to Stihler, 1991; Stihler and others, 1992; Beget and Nye, 1994; Beget and others, 1994). Mt. Saint Augustine is one of the most active volcanoes in Alaska, with major eruptions in 1883, 1935, 1964, 1976, and 1986. Mt. Redoubt erupted in 1968 and 1989-90, and Mt. Spurr erupted in 1953 and 1992 (Combellick et al., 1995:4, citing to Wood and Kienle, 1990). No historic eruptions are known for Mt. Douglas or Mt. Iliamna, although geologic evidence shows that each has erupted during the past 10,000 years (Combellick et al, 1995:4).

During their periodic violent eruptions, the active glacier-clad stratovolcanoes produce abundant ash and voluminous mudflows that have threatened air traffic and onshore petroleum facilities (Combellick et al., 1995, citing to Riehle and others, 1981; Brantley, 1990). These are examples of the two major categories of volcanic hazards that will continue to threaten activities in the region. Proximal hazards are those close to volcanoes and consist of a wide variety of flow phenomena on the flanks of volcanoes or in drainages which head on the volcanoes. Distal hazards are those farther from volcanoes, such as ashfall and tsunamis (Combellick et al, 1995:5).

The lands included in the study area are far enough from the volcanoes that they are out of range of all but the very largest eruptions (eruptions on the scale of the 1980 Mount St. Helens or 1991 Mt. Pinatubo eruption). Eruptions this large are rare, although they are certainly possible and have happened at several of the Cook Inlet volcanoes, the most recent being the eruption of Mt. Katmai in 1912.

The most common distal hazard is ashfall, where volcanic ash (finely ground volcanic rock) is lofted into the atmosphere and stratosphere by explosive eruptions, drifts downwind, and falls to the ground. There have been dozens of such events from Cook Inlet volcanoes in this century. In most cases, volcano ashfalls have been a few millimeters or less in thickness. The primary hazard of such ashfalls is damage to mechanical and electronic equipment such as engines, which ingest ash past the air filter, computers, and transformers, possibly causing electrical shorts. Ashfalls of a few millimeters should be expected throughout the Cook Inlet and Susitna basins with a long-term average frequency of a few every decade or two (Combellick et al., 1995:5).

3. Flood Hazards

Ice jam flooding occurs during breakup when ice blocks a river or stream, in effect becoming a dam. This causes water to back up and flood the adjacent land. Ice jam flooding is localized, but affects the greatest number of residents over time because of the high population concentration along rivers (Combellick et al., 1995:7, citing to J. M. Dorava, U.S. Geological Survey, personal communication, 1995).

Another cause of flooding in the study area is excessive rainfall. This results from unusual combinations of extreme meteorological conditions. Heavy flooding in September 1995 resulted from (1) interaction of tropical moisture and a deep low pressure center in the north Pacific Ocean, (2) blockage of the eastward movement of this low by a high-pressure ridge in eastern Alaska and western Canada, (3) saturated soil conditions, and (4) greater than normal glacial melt due to preceding storms. Excess sediment deposition in channels due to rapid runoff decreased the carrying capacity of the streams. The primary hazards to facilities from river flooding are high water levels, bank erosion, deposition at the river mouth, high bedload transport, and channel modification (Combellick, 1995:7).

Seasonal flooding of lowlands and river channels is extensive along major rivers that drain into Cook Inlet. Thus, measures must be taken prior to facility construction and field development to prevent losses and environmental damage. Pre-development planning should include hydrologic and hydraulic surveys of spring break-up activity as well as flood-frequency analyses. Data should be collected on water levels, ice floe direction and thickness, discharge volume and velocity, and suspended and bedload sediment measurements for analysis. Also, historical flooding observations should be incorporated into a geophysical hazard risk assessment. All inactive channels of a river must be analyzed for their potential for reflooding. Containment dikes and berms may be necessary to reduce the risk of flood waters that may undermine facility integrity.

4. Shallow Gas Deposits

Shallow gas deposits have been encountered in the Cook Inlet area and pose risks similar to overpressured sediments. The Steelhead and Grayling platforms have experienced blowouts due to shallow gas. These incidences are described in the oil spill history and risk discussion later in this chapter. The same mechanisms for blow-out prevention and well control are employed to reduce the danger of loss of life or damage to the environment.

5. Summary

There are a number of geophysical hazards that pose potential problems to future installations. However, oil and gas exploration, development, and production activities have been conducted safely in the Cook Inlet Region for over thirty years. The risks from earthquake damage can be minimized by siting facilities away from potentially active faults and unstable areas, and by designing them to meet or exceed

Uniform Building Code specifications for seismic zone 4 (highest earthquake hazard). The zone 4 specifications apply as minimums at all locations in the area (Meyer, 1993). Additional precautions should be taken to identify and accommodate site-specific conditions such as unstable ground, flooding, and other localized hazards. Proper siting and engineering will minimize the detrimental effects of these natural processes (Combellick et al., 1995:8).

B. Likely Methods of Transportation

1. Pipelines

Pipelines are the most likely method for transporting oil and gas from the study area. Transportation by truck is not economically feasible, because of the small quantities that can be moved this way and the high labor costs involved. The most likely method of transportation would involve building new pipelines to tie into existing Cook Inlet facilities. This system consists of onshore and offshore pipelines, marine terminals and tankers. How much of the infrastructure can be used will depend on the quantity of oil to be transported and whether the existing infrastructure is sound and capable of handling higher volumes of product. Otherwise totally new infrastructure will be required. It is also feasible for natural gas to be made available to local markets in and near the study area through the construction of a pipeline system. At the licensing phase however, it is impossible to predict the extent or location of new transportation facilities.

Gas pipelines use compressors to push natural gas through the lines after the gas has been treated. Separators isolate the components. Heaters prevent hydrate formation within the equipment. Dehydrators remove almost all of the water vapor. The piped gas is measured and monitored by a computer system that coordinates the operation of valves, prime movers and conditioning equipment. If a problem occurs, the computer initiates corrective actions and sounds alarms at the appropriate control points. Released gas would probably dissipate unless a spark sets it off. Ignition could result in a violent explosion. (University of Texas, 1986, pp. 297-301)

Pipelines will be either elevated or buried depending on local soil conditions and other considerations such as movement of wildlife. An individual pipeline may alternate between buried and elevated, as is the case with the Trans-Alaska Pipeline System.

a. Elevated Pipelines

Elevated pipelines are typically used in Alaska to prevent heat transfer from the hot oil in the pipeline to frozen soils, since heat would degrade the permafrost. Elevated pipelines are easy to maintain and visually inspect for leaks. However, above-ground pipelines can restrict wildlife movements unless provisions are made to allow for their safe passage. In areas where pipelines must be placed above ground, they must be sited, designed, and constructed to allow free movement of moose and other terrestrial animals.

b. Buried Pipelines

Buried pipelines are feasible as long as the integrity of the frozen soils is maintained. There are some important considerations regarding long sections of buried pipe. First is cost, which depends on length, topography, soils, and distance from the gravel mine site to the pipeline. Second, buried pipe is more difficult to monitor and maintain. However, significant technological advances in leak detection systems have been made, which increase the ease with which buried pipelines can be monitored. These systems are described below. Third, buried pipelines may involve increased loss of wetlands because of gravel fill. Finally, buried pipelines are sometimes not feasible from an engineering standpoint because of the thermal instability of fill and underlying substrate (Cronin et al., 1994:10).

2. Oil Spill Risk

Any time crude oil or petroleum products are handled there is a risk that a spill will occur. Oil spills associated with exploration, development, production, storage, and transportation of crude oil may occur from well incidents (blowouts), pipeline spills, and chronic operational spills of low volumes involving fuels and other petroleum products associated with normal operation of drilling rigs and other facilities.

MMS has performed a quantitative oil spill analysis for North Slope onshore oil and gas exploration and development spills. While direct comparisons cannot be made with the Susitna basin, the North Slope experience may be useful in estimating likelihood of spills in the study area. The pattern of crude-oil spills that occurred on the North Slope is one of numerous small spills. Thirty-two percent of crude oil spills that occurred between 1989 and 1996 were less than or equal to 2 gallons. Fifty-six percent were less than or equal to 5 gallons. During that time period, no spill greater than 1,000 bbl occurred. The database spill size ranged from greater than 1 gallon to 925 bbl. The average crude oil spill is 3.8 bbl, and the median spill size is 7 gallons. The estimated crude oil spill rate for the North Slope is 199 spills per billion bbl produced (MMS, 1997:IV-A-31).

This information shows that most spills associated with exploration or production facilities are normally quite small, 5 bbl (210 gal) or less, and are usually related to everyday operations. Even a worst case oil discharge from an exploration facility, production facility, or pipeline is restricted by the maximum storage capacity or the well's ability to produce oil. For example, a well with a maximum production rate of 2,500 bbl per day will only spill a maximum of 2,500 bbl per day (Powers, 1989:2). As another example, a 14-inch pipeline can store approximately 1,000 bbl of oil per mile of pipeline length. Accordingly, under static conditions if oil were lost from a five mile stretch of pipeline (a hypothetical distance or spacing between emergency block valves), then a maximum of 5,000 bbl of oil is all that would be discharged into the environment.

According to the most recent statistics, worldwide tanker spill rates are declining. In 2000, they were calculated at a rate of 1.20 spills (greater than 1000 bbl) per billion bbl transported. This is down from 1.30 spills per billion bbl transported in 1994. Spills for North Slope also showed a decline in this period from 1.10 spills per billion bbl transported to 0.98 (Anderson, 2000).

The state has enacted stringent oil spill prevention, control, and cleanup legislation (AS 46.04.010-900). The statute requires oil spill contingency plans which include methods for detecting, responding to, and controlling blowouts; prevention, control, and cleanup plans; and location and identification of cleanup equipment.

The risks associated with producing and transporting oil can never be reduced to zero. There is always some chance that spills will result from exploration, production, storage, and transportation of oil. However, the state's goal is to reduce the possibilities of spills to a level of acceptable risk and to improve the ability to respond to spills when they happen.

The stationary nature of North Slope exploration and production facilities and the predictability of maximum spill rates simplify the development and implementation of oil spill contingency plans. Even TAPS, with the tremendous quantities of oil flowing through that system, is designed to quickly shut down in the event of a rapid decrease in pressure such as would happen if there were a major break in the line. This safety feature, and many others, such as daily visual monitoring and block valves along the entire pipeline, limits the volume of a spill.

C. Oil Spill Prevention

The technology for monitoring pipelines is continually improving. A number of leak detection systems are already in use or proposed for Alaska oil and gas pipeline development. Elements of these systems could be incorporated into any new pipelines constructed in the study area. Leak detection systems and effective emergency shut-down equipment and procedures are essential in preventing discharges of oil from any pipeline which might be constructed in the study area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan, 1986:68). Industry on the North Slope currently uses the volume balancing method to determine this rate which involves comparing input volume to output volume.

Leak detection methods include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon, Mensik, and Luk 1988). The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer-based leak detection through a Real-Time Transient Model has come into use. This technology can minimize spills from both new and old pipelines (Yoon and Mensik, 1988a).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989:23). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

Three other systems can be employed which detect leaks down to 0.12 percent of rated capacity (100 bbl per hour). These include Line Volume Balance, Deviation Alarms, and Transient Volume Balance.

1. Line Volume Balance

LVB checks the oil volume in the pipeline every 30 minutes. The system compares the volume entering the line with the volume leaving the line, adjusting for temperature, pressure, pump station tank-level changes, and slackline conditions.

2. Deviation Alarms

There are three types of deviation alarms: pressure, flow, and flow rate balance. Pressure alarms are triggered if the pressure at the suction or discharge of any pump station deviates beyond a certain amount. Flow alarms are triggered if the amount of oil entering a pump station varies too much from one check time to the next. Flow rate balance alarms are triggered if the amount of oil leaving one pump station varies too much from the amount entering the next pump station downstream. This calculation is performed on each pipeline section about six times a minute.

3. Transient Volume Balance

TVB can both detect whether a leak may be occurring and identify the probable leak location by segment, especially with larger leaks. While the LVB leak detection system monitors the entire pipeline, the TVB system individually monitors each segment between pump stations. Since the TVB indicates in which area a leak may be occurring, focused reconnaissance and earlier response mobilization are possible (Alyeska Pipeline, 1999a).

4. LEOS

Another detection system that is available is LEOS (Leck Erkennung und Ortangs System), a leak detection and location system manufactured by Siemens AG. The system has been in use for 21 years and in over thirty applications.

LEOS consists of a three-layer gas-sensor tube that is laid next to the pipeline. The inner layer is a perforated gas transport tube of modified PVC. A diffusion layer of EVA surrounds and allows gasses to enter the inner tube. A protective layer of braided plastic strips forms the outer layer. The tube is filled with fresh air, and the air is evacuated through a leak detector at regular intervals. If leak occurs, hydrocarbon gasses associated with the leak enter the tube and are carried to the gas detector. The system is totally computer controlled, self-checking and re-setting. Background gasses are calibrated at setup and checked regularly. The system will pick up previous contamination and organic decomposition. The location of the leak is determined by monitoring the time that leaked gas arrives at the detection device.

The system is very low maintenance and will last the life of the pipeline. Special protective adaptations will be made for the cold temperatures in which the system will operate and for the backfill installation method that will be used to install the pipeline. The tube will be placed in a protective cover, and the system will be tested continuously as the segments are installed. LEOS will be strapped to the oil pipeline next to the poly spacers that will separate the gas line from the oil line. The system will detect leaks from both lines, and operators will be able to tell the difference between the two. Engineers estimate that it will take about 5 to 6 hours for leaked molecules to migrate to the LEOS tube. The air inside the tube will be evacuated and tested every 24 hours

5. Smart Pigs

Design and use of "smart pigs," data collection devices that are run through the pipeline while it is in operation, has greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. These pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems. The TAPS operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures.

6. FLIR

Phillips Petroleum utilizes a comprehensive FLIR (Forward Looking InfraRed) pipeline monitoring program in the Kuparuk oil field to assist in detecting pipeline leaks and corrosion. InfraRed sensors have the ability to sense heat differentials. Since Kuparuk oil flows from the ground at temperatures in excess of 100F, a leak shows up as a "hot spot" in a FLIR video. In addition, water-soaked insulation surrounding a pipeline is visible because of the heat transfer from the hot oil to the water in the insulation and finally to the exterior surface of the pipeline. FLIR is effective 80 percent of the time in discovering water-soaked insulation areas that have produced corrosion on the exterior wall of the pipeline (ARCO, 1998).

FLIR also has applications in spill response and was used to image spills at both Prudhoe Bay and Kuparuk. The video frames were processed and registered into a GIS map database. The map database with the overlaid picture of the spill site was then used to quickly and accurately determine the area of the spill. This action allowed swift and accurate reporting of the spill parameters to the appropriate agencies. The video footage of the spill area allowed the incident command team to receive near real-time information in IR and color. This information permitted timely decisions to be made and the results of those decisions to be reviewed with the subsequent fly-over zone site. Various agencies involved in the process were able to see and verify the results of the cleanup process (ARCO, 1998).

To insure safe operation, pipeline operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would also perform preventative maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections.

No oil or gas may be transported until the operator has obtained the necessary permits and authorizations from federal, state, and local governments. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed.

Mitigation Measures

The following are summaries of some applicable mitigation measures designed to mitigate potential impacts from oil and gas transportation. For a complete listing of mitigation measures and licensee advisories see Chapter Seven. Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

- Oil Spill Prevention and Control – Pursuant to regulations 18 AAC 75 administered by ADEC, licensees are required to have an approved oil discharge prevention and contingency plan (c-Plan) prior to commencing operations. Pipeline gravel pads must be designed to facilitate the containment and cleanup of spilled fluids. Containers with a total storage capacity of greater than 55 gallons which contain fuel or hazardous substances shall not be stored within 100 feet of a waterbody.
- Pipelines must be located upslope of roadways and construction pads and must be designed to facilitate the containment and cleanup of spilled hydrocarbons. Pipelines, flowlines, and gathering lines must be designed and constructed to assure integrity against climatic conditions and other geophysical hazards.
- Pipeline Siting – Whenever possible, onshore pipelines must utilize existing transportation corridors and be buried where soil and geophysical conditions permit. Abover ground pipelines must be designed, sited, and constructed to allow for the free movement of moose and other wildlife.